Board Staff Interrogatory #80

Issue Number: 5.1
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

Reference:
Ref: Exh E2-1-1 page 2

OPG states that its outage forecasts are based "on actual experience with similar work performed in the past at OPG and other organizations."

a) From which other organizations has OPG sought experience? How have these experiences impacted the forecast outage lengths in this application?

b) Has OPG sought experience from similar work performed at Ontario facilities operated by Bruce Power? If not, why not? Is so, please explain what was learned and provide examples of how it has impacted any of the forecast outages in this application.

Response

a) OPG continually seeks experience regarding outage performance from a number of organizations, including the Institute of Nuclear Power Operations, Candu Owners Group, Bruce Power, and New Brunswick Power (Point Lepreau Nuclear Generating Station). OPG uses the information gathered from these groups to inform specific outage work programs and activities. including:

- the use of new technologies such as the use of drones for inspections and phased array quality control inspections to replace radiography
- new tooling such as the Rapid Delivery Machine for fuel channel inspection programs
- best practices and processes for single fuel channel replacements
- best practices for execution of the Vacuum Building Outage (VBO)

In addition, OPG invites representatives from Bruce Power and Kinetrics to participate in major scope meetings and outage readiness reviews.

Where applicable, cost and schedule information are built into OPG's outage programs.

b) OPG has sought experience from similar outage work at Bruce Power, as discussed in OPG's response to part (a) above. Some examples of operating experience learned from Bruce Power and applied to OPG outages are as follows:

- The use of divers to inspect the dousing water tank in the vacuum building during a VBO as opposed to draining the tank, resulting in lower environmental issues and lower costs associated with less scaffold resources required
- The use of drones for internal inspections of the vacuum building structure, resulting in faster inspections and lower costs
- Improvements in outage execution management and oversight, including the implementation of a Maintenance war room and Outage Control Center technology and training improvements

Board Staff Interrogatory #81

Issue Number: 5.1
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

Reference:
Ref: Exh E2-1-1 pages 4 and 8
For its Darlington facilities, OPG has forecasted a Forced Loss Rate (FLR) of 1% for 2016 through 2019, 4.2% for 2020 and 3.0% for 2021. OPG states that the increase to the FLR in 2020 and 2021 "reflects the return to service of Darlington Unit 2 from its refurbishment outage and is consistent with industry operating experience." Chart 3 shows an overall average FLR of 2.9% for Darlington facilities over the 2010-2015 period.

On page 8, OPG states that its forecast FLR of 1% "is aggressive" but "achievable based on expectations that OPG executes ongoing initiatives to improve equipment reliability that will stabilize Darlington's FLR."

a) What experience forms the basis for OPG's forecast increase to the FLR in 2020 and 2021?
b) Please reconcile the expectation that OPG's ongoing initiatives will "improve equipment reliability that will stabilize Darlington's FLR" with the forecast increase to the FLR in 2020 and 2021.
c) Given the history of under-production shown in chart 2 of Exh. E2-1-1 (line 3 Actual vs line 1 OPG Application), why is OPG proposing an "aggressive" FLR?
d) Please confirm that the planned "warranty" outages in 2020 and 2021 for unit 2 are not included in the forecast FLR for unit 2.
e) The unit 2 FLR is forecast to be 12 percent in the year of return to service and the year immediately following. Is OPG expecting unit 2 to be offline an additional 44 days (12 per cent of 365) in 2020 and 2021?

Response

(a) OPG's Unit 2 post refurbishment FLR forecast is based on the results of other CANDU nuclear stations which experienced significant forced outages due to emergent equipment issues post refurbishments. Nuclear stations examined included Point Lepreau, Bruce A, Pickering A, and Wolsong.

Based on this information, FLR for Unit 2 was forecast to be 12% in 2020 and 6% in 2021. The other three Darlington units are forecast to remain at OPG's long term FLR goal of 1%, which results in a total station FLR target of 4.2% in 2020 and 2% in 2021.

(b) OPG believes that the equipment reliability, parts improvement, and human performance initiatives discussed at Ex. F2-1-1, as well as capital project investments in aging and life cycle management programs, will allow Darlington to achieve the 1% FLR objective on the three operating units during the rate-setting period prior to each of their refurbishments. These initiatives will also allow Unit 2 to achieve the long-term goal of 1% FLR post refurbishment after an initial post-refurbishment period as discussed in part (a) above.

(c) OPG believes that the Darlington 1% FLR target is challenging but achievable in light of recent and ongoing initiatives to improve equipment reliability and ongoing investments to deal with equipment aging and life cycle management issues. These initiatives include replacement of the Primary Heat Transport Motors, which contributed significantly to higher than planned FLR in 2015 and 2016.

(d) Confirmed. The 'warranty' outages in 2020 and 2021 are planned outages, not forced outages and are included in the planned outage days in 2020 and 2021. As a result, the planned warranty outages would not be included in the forecast FLR for Unit 2.

(e) No. The 12% FLR forecast in 2020 and 6% FLR in 2021 is equivalent to 32 days and 20 days offline, respectively. FLR is calculated as a percentage of days the units are expected to be online, which excludes all planned outage days (including refurbishment planned outage days).

Board Staff Interrogatory #82

Issue Number: 5.1
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

Reference:
Ref: E2-1-1, page 3
OPG states that it will undertake two "warranty" outages on Darlington unit 2 in 2020 and 2021. OPG states that the "need for these post-refurbishment mini-outages is based on operating experience at other nuclear facilities that underwent major refurbishment."

a) Does OPG have any documentation or reports to support the need for these "mini-outages"? If so, can OPG file these reports with the OEB? If not, please provide further details regarding the experiences supporting the need for these outages.

b) OPG states that the need for these outages is based on experience at other nuclear facilities. Please identify which other nuclear facilities OPG is referring to specifically. Are these CANDU facilities or other technologies?

c) OPG's first warranty outage on Darlington Unit 2 is scheduled to last for 55 days in 2020.

   i. On what basis was the 55 day duration chosen? Does OPG have examples or experience from previous refurbishment processes to support this specific length of outage?
   ii. What types of equipment repair does OPG anticipate will be required during this outage? Is there documentation to support these expectations?

d) Referring to these outages as "warranty" outages implies that vendors may assume some liability for costs associated with these outages.
   i. Are vendors liable for any costs associated with these outages? If so, is this liability specifically addressed in the vendor contracts?
   ii. Can OPG provide documentation to define these liabilities? If vendors are liable for costs, what are the limits of their liability?
   iii. Does this liability include compensation for lost production?

e) OPG's submission allows for a second warranty outage of 33 days duration for Unit 2 in 2021. OPG states that "the shorter duration is due to an expectation that the majority of scope required to be addressed post-refurbishment will be completed during the first post refurbishment mini-outage in 2020."
   i. How certain is OPG that this second outage will be required? What experience underpins this allowance for a second outage?
   ii. Does OPG have any concerns that scheduling a second warranty outage will

affect vendors' performance in addressing corrective actions during the first warranty outage?

iii. Do vendors have performance incentives that could lessen the need for, or, the length of, the second warranty outage?

Response

a) OPG does not have any documentation or reports to support the need for the post commissioning mini-outages. The need for these outages is based on examining operating experience at other refurbished CANDU plants – Point Lepreau, Bruce A, Pickering A, and Wolsong – which shows that a refurbished plant can expect to encounter a number of emergent equipment related issues immediately following post refurbishment that can result in forced outages (see Ex. L-5.1-1 Staff-81) and/or the need for small scope mini outages in the period immediately following commissioning. In particular, Point Lepreau was required to schedule a number of outages post commissioning to fix emergent issues that arose.

b) As identified above, the nuclear facilities that OPG examined to determine the needs for the post commissioning mini-outages were Point Lepreau, Bruce A, Pickering A and Wolsong. All are CANDU plants.

c)

i. The 55 day duration was chosen based on an assessment of the required length of outage to fix a major equipment issue. OPG's determination was based on examples from the Point Lepreau refurbishment and Pickering A return to service where post commissioning issues with governor valves, high leakage to collection, liquid zone control system and moderator system valves were encountered.

ii. In addition to the examples provided above, a failure of newly installed components such as pump seals might result in high leakage and require a shutdown to fix. As well, there is a risk that laid up systems may experience emergent degradation requiring an outage to repair. For example, feedwater or turbine-generator components required for full power operation may have degraded during the multi-year refurbishment layup and require fixing in a post commissioning mini-outage.

d)

i. OPG will not know until the outage if there is any work subject to the contractual warranty provisions required. If there is, OPG's contracts generally provide that the warranty work is carried out at the contractors' costs.

ii. The contracts vary with respect to warranty obligations and limitations of liability. Please see the contract summaries at Ex. D2-2-3, Attachments 1 to 5 and the full contracts at Ex. D2-2-3, Attachments 6 to 10 for details on the warranty clauses and the limitation of liability clauses in the contracts.

iii. OPG's contracts do not generally provide that a contractor will pay for lost production. Please see the warranty clauses in the contract summaries and the contracts filed at Ex. D2-2-3, Attachments 1 to 10 for more detail.

e)

i. OPG is reasonably certain that this outage will be required. Although it is impossible to specifically identify the exact need, again based on operating experience at other CANDU plants as identified above, equipment issues resultant for new and laid up equipment not identified in the first 6 months following refurbishment will require a second post commissioning mini-outage to fix.

ii. Warranty issues identified in the outage should be corrected as quickly as possible. OPG is not concerned that scheduling a second warranty outage will affect a contractor's performance as it is in the contractor's interest to fulfill their warranty obligations as soon as possible. Late corrections will increase a contractor's cost for fulfilling their warranty obligations.

iii. Other than the cost minimization incentive indicated in part ii, there are no performance incentives associated with a potential second warranty outage.

Board Staff Interrogatory #83

Issue Number: 5.1
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

Reference:
Ref: E2-1-1, page 4
OPG has stated that it expects Pickering's annual FLR to stabilize at 5% from 2016 through 2021. This was attributed to equipment reliability and fuel handling improvement initiatives.

a) Generally, what factors are considered in the assessment when forecasting the FLR and how is it calculated?

b) What are the specific factors, assumptions and experiences that have led to the expectation of an FLR of 5% over the 2016-2020 period for the Pickering units.

Response

a) Forced Loss Rate ("FLR") forecasts are developed by assessing a number of interlinked factors. As discussed at Ex. E2-1-1, pp. 8-9, these include:

- An assessment of the FLR historical trending performance
- An assessment of Equipment Reliability Index and Plant System Health, looking at historical trends and expected future equipment condition, including fuel handling equipment reliability.
- A review of maintenance backlogs, both historical trends and expected future performance
- An assessment of human performance, both historical trends and expected future performance.
- An assessment of capital and OM&A project investments, and the timing of specific project availability for service.
- Any known improvements or plant material condition issues.

The determination of FLR is described at Ex. E2-1-1 Attachment 1, p. 1.

b) The forecast of a 5% FLR for Pickering over the 2016 to 2020 period is based on the following assumptions:

Witness Panel: Nuclear Operations and Projects

- Pickering has continued to make investments in programs to improve equipment reliability and plant system health, including a multi-year trend of reducing backlogs. This included identifying and executing key reliability work orders over a multi-year period. Corrective maintenance backlogs are at a multi-year low for the station.

- Pickering has made improvements and intends to continue to improve in the area of human performance.

- OPG continues to make capital investments in Pickering, with a focus specifically on systems that have previously been associated with high production losses as well as components at end of life where there is increased risk of unforeseen failures. These include fuel handling equipment reliability improvements and replacements of motors and seals associated with the primary heat transport and shutdown cooling systems. Capital investments are assessed from a value for money perspective based on their cost versus their potential to reduce the risk of forced outages.

- Chart 4 from Ex. E2-1-1, p. 9 that is reproduced below shows Pickering's FLR averaged 8.5% over the period 2010 to 2015 due in particular to excellent performance in 2015. A forecast of 5.0% for Pickering FLR is consistent with Pickering's improving FLR trend.

Chart 4

Pickering Forced Loss Rate

	2010	2011	2012	2013	2014	2015	Avg
FLR (%)	9.3	11.6	7.0	9.7	10.7	2.9	8.5

Board Staff Interrogatory #84

Issue Number: 5.1
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

Reference:
Ref: Exh E2-1-2, page 5 – 8 Ref: Exh E2-1-2, Table 1
In the evidence, OPG has highlighted forced extensions to planned outage (FEPO) days as reasons for under-production as compared to the OEB-approved 2015 and 2014 production forecasts. In Table 1, OPG's Budget and OEB Approved production forecasts do not include any estimated value for FEPO.

a) Has OPG factored FEPO into its planned outage forecasts?

b) Has OPG undertaken any statistical analysis of historical trends in FEPO days? If so, please provide the analysis.

c) Do the lengths of the planned outages included in OPG's nuclear production forecast include any contingency days for unexpected delays in completion of projects? If so, what is used to calculate the appropriate number of contingency days to be included?

Response

a) and c):

No, OPG does not directly factor FEPO or losses due to project delays into its planned outage forecasts. However, OPG assesses specific potential risks associated with an outage and assigns risk allowances associated with those risks to determine the outage duration. These risks in some cases are risks that had been identified as causing forced extensions to planned outages in the past. The number of days included in the outage plan for specific risks is based on the assessed consequential impact of the risk. The production forecast addresses overall risk to completion of the outage schedule. This methodology is consistent with the OEB approved approach in EB-2013-0321 (see Ex. E2-1-1, p. 2).

b) OPG does not perform a statistical analysis of the historical trends in the number of FEPO days. The number and scope of planned outages vary year over year, as well as the underlying cause for the FEPO and therefore the number of FEPO days cannot be trended over time. However OPG does complete post-outage analysis (referred to as a "common cause analysis") to assess, among other things, the reasons for a forced extension of a planned outage, with the intent to develop actions to prevent such occurrence in future outages.

Witness Panel: Nuclear Operations and Projects

Board Staff Interrogatory #85

Issue Number: 5.1
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

Reference:
Ref: Exh E2-1-1, Chart 2

Chart 2 shows OPG's historical production performance, as compared to its applied for and approved production forecast.

a) Does OPG perform any scenario analysis when preparing its nuclear production forecasts, i.e. preparing a range of forecasts with optimistic and pessimistic assumptions? If so, please provide the production forecasts for each scenario.

b) Does OPG perform any analyses to assess the expected statistical variability in its production forecasts? Is so, please provide such analyses.

c) What are the key elements/assumptions underpinning its proposed production forecast that pose the greatest risk to achieving its production goals?

d) Given OPG's history of not meeting its applied for and the OEB-approved production forecast, how would OPG characterize the assumptions in its proposed 2017-2021 production forecast (e.g. optimistic/aggressive, pessimistic/conservative)?

Response

a) OPG does not perform any scenario analysis when preparing its nuclear production forecasts.

b) OPG does not perform any analysis to assess the expected statistical variability in its production forecasts as there is too much variability between outage program scope and duration to yield meaningful results.

c) The key risks to achieving the proposed production forecast are as follows:
- Forced or unbudgeted planned outages to fix equipment
- Human performance errors
- Station fuel handling equipment issues that delay outage completion or cause unit derates
- Emergent work that must be completed during an outage
- Inspection results that extend planned outages
- Outage delays due to resourcing issues

For discussion of other factors that could affect OPG's production forecast, see Ex. L-11.5-1 Staff-270.

d) OPG characterizes the assumptions in the proposed production forecasts as challenging, but achievable.

Board Staff Interrogatory #86

Issue Number: 5.1
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

Reference:
Ref: Exh A1-4-3

OPG notes that it is currently planning to extend the safe operation of its Pickering nuclear units beyond 2020.

Please provide a production forecast for OPG's Pickering station reflecting the scenario in which OPG does not receive the necessary regulatory approvals to extend the operation of its Pickering station.

Response

Chart 1 reflects the production scenario for a 2020 end date that OPG provided to the IESO for purposes of developing the extended operations economic assessment in October 2015.

Developing a production forecast where the CNSC does not approve extended operations in 2018 as part of the relicencing process would be purely speculative. OPG is unable to predict any requirements that might be imposed by the CNSC as part of that regulatory process and the resulting impacts of those requirements on production (see L-6.5-5 CCC-33).

Chart 1

Scenario (TWh)	2017	2018	2019	2020	2021	2022	2023	2024
Pickering Operations NOT approved beyond 2020	20.0	20.4	20.5	23.4	n/a	n/a	n/a	n/a

Board Staff Interrogatory #87

Issue Number: 5.1
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

Reference:
Ref: Exh E2-1-1-page 2 and 8

OPG notes in its application that it is following previous OEB decisions with respect to the production forecast. OPG specifically cites the OEB's observation that there is no need for an adjustment to production from "unforeseen major events" as a result of OPG's basing its production forecast on actual experience with maintenance performed in the past at OPG and other organizations.

a) OPG's proposal states that "the planned outage durations include a station level allowance for uncertainty related to potential discovery work. They also include a nuclear fleet level allowance to address risks to the completion of the outage on schedule, risks that could emerge from fleet aging issues, or from complexity in fleet level activities (e.g., availability of Inspection Maintenance Service resources to service multiple outages)."
   i. Is this uncertainty component for outages expressed as a separate input in the planning process?

   ii. How is this uncertainty component included in the outage schedule - is it a percentage of total outage schedule or an estimate of hours or days of uncertainty as determined from previous experience with similar activities?

b) Can OPG provide further elaboration on how it determines this uncertainty component and explain how it is materially different from an allowance for "unforeseen major events"?

c) When in 2021 is the six unit Pickering VBO scheduled to commence? Is there any flexibility in this schedule or is it governed by the CNSC?

Response

a)
   i. No, the risk allowances are assessed and built into each planned outage duration as part of the outage planning process.

   ii. The risk allowances are included in each planned outage schedule as an estimate of the number of hours/days based on an assessment of the potential consequence and probability of that risk being realized. The assessment of the

number of hours/days required for some risks is proportional to the length of the total outage schedule, based on historical trends.

b) As part of the outage and generation planning process, risks to an outage are identified and assessed against the probability of them occurring and the consequence or impact on the outage. The risks are also assessed against mitigation actions to determine the residual risk to the outage. Based on that assessment, risk allowances are added to the outage duration. This is materially different from an allowance for "unforeseen major events". The risk allowances are for potential risks known to the outage and derived as part of outage planning, as opposed to an allowance for "unforeseen major events", which is a contingency for unknown risks and separate from the outage planning process. This methodology is consistent with the OEB approved approach in EB-2013-0321 (see EB-2016-0152, Ex. E2-1-1, p. 2).

c) The six unit Pickering NGS Vacuum Building Outage is scheduled to begin on May 1, 2021. The outage frequency for a Vacuum Building Outage at Pickering is dictated by Canadian Safety Standards (CSA) N287.7 and OPG's Licence Condition Handbook.

OPG's experience is that there may be some flexibility in moving vacuum building outages. Approval to delay a Vacuum Building Outage must be granted by the CNSC and is contingent on inspection data along with the ability to show, based on accepted methodologies, that there will be no safety impact or increased risk.

If Vacuum Building Outage scheduling flexibility leads to changes in the timing of Vacuum Building Outage, OPG would address the potential impact on the nuclear production forecast through the proposed mid-term production review, as described at Ex. A1-3-3.

Board Staff Interrogatory #88

Issue Number: 5.1
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

Reference:
Ref: Exh E2-1-1-1 page 3
In the Glossary of Outage and Generation Performance Terms OPG provides an explanation of planned outages and the procedures for scheduling outages with the IESO.

a) OPG states that it submits its planned nuclear outage schedule to the IESO early to secure an early time-stamp date.
   i. Typically, how "early" is early, noting that 28 days prior to the requested start date is the minimum?
   ii. Does the type and/or duration of outage contemplated determine how far in advance the request is submitted?
   iii. Has OPG submitted any requests for outages that are included in this production forecast?

b) According to the proposal a planned outage duration cannot be revised (increased or decreased) after the planned outage has commenced. This implies that at any time prior to the outage commencing, OPG can revise the duration of the specific outage. Is this correct?
   i. In OPG's experience has there ever been an instance of an outage duration being overestimated, resulting in an avoidable loss of production?
   ii. In OPG's experience has there ever been an instance of outage duration being underestimated, requiring a declaration of a "forced extension to planned outage(s)" (FEPO)?

c) What are the financial and revenue implications to OPG of either over- or underestimating planned outages in submitting its outage schedule to the IESO?

d) Is there an advantage to underestimating outage durations to avoid the certainty of lost revenues in case of an overestimate?

Response

(a)
   i. OPG submits planned outages to the IESO when it finalizes its business plan in order to secure a priority position in the schedule and minimize the risk that the IESO will not approve the outage. This is done as much as 3 years or more in advance. Since 2014, the minimum period for submitting planned outages to the IESO is five

business days prior to start of an outage. Prior to 2014, it was three business days. The reference to 28 days prior to requested start date is not an IESO requirement, but rather a rule for reporting purposes related to the definition of planned versus forced extension to outages from World Association of Nuclear Operators ("WANO").

ii. The type and/or duration influence how far in advance the request is submitted. Longer planned outages are submitted well in advance to aid the IESO with system planning. Shorter outages such as the PHT Pump motor replacement outages are typically submitted in the budget year once scope has been finalized and optimum timing of the outage has been determined.

iii. Yes, OPG has submitted requests for outages that are included in the production forecast.

(b) No. OPG can revise the duration of a specific outage at any time with the IESO, including while a planned outage has commenced. However, for purposes of classification related to the WANO definition of planned outages (and unrelated to IESO requirements), if the change is submitted less than 28 days ahead of when the outage was to commence, the change (if an extension to the outage) is no longer considered part of the planned outage, but is rather deemed a forced extension to a planned outage ("FEPO"). For example, if the outage finish date was extended by a week from the original IESO submission less than 28 days from the start of the outage, then that week would be considered FEPO and not part of the planned outage under WANO definitions.

i. There have been cases where outages have come in ahead of the planned schedule resulting in a gain in production (as the unit is returned as soon as an outage is complete),
ii. There have been cases where outages have been longer than the planned schedule, resulting in lost production due to FEPO.

(c) and (d)

There is no link between the durations submitted to the IESO and revenues, so there is no advantage to overestimating or underestimating outage durations. The submission of outage durations to the IESO is for system planning purposes. Payment is based on actual production and is not linked to durations submitted to the IESO for system planning purposes.

AMPCO Interrogatory #108

Issue Number: 5.1
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

Reference:
Ref: A1-4-1 Page 2

a) Please provide the total generation (TWH) from OPG's regulated facilities for the years 2010 to 2015 and forecast for 2016.

Response

See Chart 1 below. Note that the 2016 forecast is as of September 2016.

Chart 1

	2010	**2011**	**2012**	**2013**	**2014**	**2015**	**2016 Forecast**
Darlington	26.5	29.0	28.3	25.1	28.0	23.3	25.9
Pickering	19.2	19.7	20.7	19.6	20.1	21.2	20.1
Total Nuclear	**45.8**	**48.6**	**49.0**	**44.7**	**48.1**	**44.5**	**45.9**

CCC Interrogatory #24

Issue Number: 5.1
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

Reference:
Reference: Ex. E2/T1/S1

Please list in table form all of the planned outages that are included in the test period forecast, the duration of each planned outage, the lost production resulting from each planned outage and the dollar value of each planned outage based on the proposed nuclear payment amount that would result if OPG is able to cancel the planned outage.

Response

Please see Table 1 attached.

Year		Outage	Unit Affected	Description	Outage Duration (days)	Forecast Production (TWh) Impact Due to Outage	Revenue Impact of Outage ($M)
2017	Pickering	P1711	Unit 1	Planned Outage	204.9	2.6	168.0
		P1742	Unit 4	Mid-Cycle Outage	43.0	0.5	35.2
		P1751	Unit 5	Planned Outage	160.7	2.0	132.0
		P1761	Unit 6	Planned Outage	133.0	1.7	109.2
		Total			**541.6**	**6.8**	**444.4**
	Darlington	D1711	Unit 1	Planned Outage	108.4	2.3	152.9
		DNRU2	Unit 2	Refurbishment Outage	365.0	7.8	514.8
		D1731-PD	Unit 3	Planned Derate	2.5	0.1	3.5
		D1732	Unit 3	PHT Pump Motor Outage	20.0	0.4	28.2
		D1741-PD	Unit 4	Planned Derate	2.5	0.1	3.5
		D1742	Unit 4	PHT Pump Motor Outage	20.0	0.4	28.2
		Total			**518.4**	**11.1**	**731.2**
Total 2017					**1,060.0**	**17.9**	**1,175.6**
2018	Pickering	P1812	Unit 1	Mid-Cycle Outage	43.0	0.5	39.1
		P1841	Unit 4	Planned Outage	144.1	1.8	131.2
		P1871	Unit 7	Planned Outage	193.5	2.4	176.4
		P1881	Unit 8	Planned Outage	150.2	1.9	136.9
		Total			**530.8**	**6.6**	**483.6**
	Darington	D1811	Unit 1	PHT Pump Motor Outage	20.0	0.4	31.3
		DNRU2	Unit 2	Refurbishment Outage	365.0	7.8	571.4
		D1831	Unit 3	Planned Outage	103.3	2.2	161.7
		D1841	Unit 4	PHT Pump Motor Outage	20.0	0.4	31.3
		Total			**508.3**	**10.9**	**795.8**
Total 2018					**1,039.1**	**17.5**	**1,279.4**
2019	Pickering	P1911	Unit 1	Planned Outage	128.5	1.6	129.8
		P1942	Unit 4	Mid-Cycle Outage	43.0	0.5	43.4
		P1951	Unit 5	Planned Outage	165.6	2.1	167.6
		P1961	Unit 6	Planned Outage	180.1	2.2	182.3
		Total			**517.2**	**6.5**	**523.1**
	Darlington	D1911	Unit 1	PHT Pump Motor Outage	20.0	0.4	34.8
		D1912-PD	Unit 1	Planned Derate	2.5	0.1	4.3
		DNRU2	Unit 2	Refurbishment Outage	365.0	7.8	634.3
		P1931-PD	Unit 3	Planned Derate	2.5	0.1	4.3
		D1941	Unit 4	Planned Outage	99.1	2.1	172.2
		Total			**489.1**	**10.5**	**850.0**
Total 2019					**1,006.3**	**16.9**	**1,373.1**
2020	Pickering	P2012	Unit 1	Mid-Cycle Outage	43.0	0.5	48.2
		P2041	Unit 4	Planned Outage	164.5	2.0	184.4
		P2071	Unit 7	Planned Outage	102.5	1.3	115.1
		P2081	Unit 8	Planned Outage	188.9	2.4	212.2
		Total			**498.9**	**6.2**	**560.0**
	Darlington	D2011	Unit 1	Planned Outage	108.2	2.3	208.7
		DNRU2	Unit 2	Refurbishment Outage	45.0	1.0	86.8
		D2022-PD	Unit 2	Planned Derate	2.5	0.1	4.8
		D2021	Unit 2	Post Refurb Mini Outage	55.0	1.2	106.1
		DNRU3	Unit 3	Refurbishment Outage	321.0	6.9	619.2
		D2042-PD	Unit 4	Planned Derate	2.5	0.1	4.8
		D2041	Unit 4	PHT Pump Motor Outage	20.0	0.4	38.6
		Total			**554.2**	**8.6**	**773.6**
Total 2020					**1,053.1**	**14.8**	**1,333.5**
2021	Pickering	P2111	Unit 1	Planned Outage	150.5	1.9	187.3
		P2141	Unit 4	Vacuum Building Outage	30.0	0.4	37.3
		P2151	Unit 5	Planned Outage	179.7	2.2	224.1
		P2161	Unit 6	Planned Outage	112.6	1.4	140.4
		P2162	Unit 6	Vacuum Building Outage	30.0	0.4	37.4
		P2171	Unit 7	Vacuum Building Outage	30.0	0.4	37.4
		P2181	Unit 8	Vacuum Building Outage	30.0	0.4	37.4
		Total			**562.8**	**7.0**	**701.3**
	Darlington	DNRU1	Unit 1	Refurbishment Outage	200.0	4.3	428.3
		D2121	Unit 2	Post Refurb Mini Outage	31.2	0.7	66.8
		D2122-PD	Unit 2	Planned Derate	2.5	0.1	5.4
		DNRU3	Unit 3	Refurbishment Outage	365.0	7.8	781.6
		D2142-PD	Unit 4	Planned Derate	2.5	0.1	5.4
		D2141	Unit 4	PHT Pump Motor Outage	20.0	0.4	42.8
		Total			**621.2**	**13.3**	**1,330.2**
Total 2021					**1,184.0**	**20.3**	**2,031.5**

EP Interrogatory #21

Issue Number: 5.1
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

Reference:
Exhibit E2, Tab 1, Schedule 2, table 1

OPG has consistently missed its approved nuclear production forecasts.

1. Can you provide how much money OPG has collected through its variance account as a result of missing approved production forecasts from 2013-2015?

2. Does OPG have an updated nuclear production forecast for 2016?

Response

1. The OEB has not established a variance account that permits recovery of lost revenue due to the differences between OPG's actual and forecast nuclear production and therefore OPG has not collected any money as a result of missing its approved production forecast from 2013-2015 or for any other period.

2. The nuclear production forecast for 2016 as of the end of September is 45.9 TWh.

EP Interrogatory #22

Issue Number: 5.1
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

Reference:

Can OPG list the amount of power (in TWh) it has curtailed from its nuclear reactors in 2013, 2014, 2015 and to date in 2016. Can it do so quarterly.

Response

OPG very rarely is asked to curtail power from its nuclear reactors. Below is a list of quarters where OPG was asked to curtail power and the amounts.

2013-Q2 – 0.002TWh
2016-Q3 – 0.02TWh

Each of these reductions has been at Darlington. Pickering has not been asked to curtail power in the requested time period.

OAPPA Interrogatory #6

Issue Number: 5.1
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

Item 4: Is the production forecast sufficient for the Test Period.

4-OAPPA-1

Reference:
Re: Exhibit E2-1-1, Production Forecast and Methodology Nuclear, Section 2.0, Page 4, lines 3 to 14
Exhibit D2-1-3, Capital Projects Nuclear Operations, Page 6, lines 27-31 and Page 7, lines 1 to 7

The production forecast considers eight (8) mini-outages of 20 days in duration each, to replace 16 PHT pumps during the Test Period. We understand that the June 2015 failure of a PHT pump took 25.75 days to replace, resulting in 0.54 TWh of lost production (or ~ 0.02097 TWh/day).

a) As they have been specifically identified, are we correct in our understanding that these eight outages will occur independently of the Units 2, 3 and 1 DRP outages, scheduled in 2016, 2020 and 2021 respectively or has any consideration been given to replacing these PHT's during the DRP unit over-hauls, concurrently?

b) Are we correct in our understanding that these eight outages will result in 8 outages x 20 days x 0.02097 TWh / outage day = 3.355 TWh of non-production during the Test Period? If not, can you advise as to actual production loss represented in the schedule?

c) Assuming a planned outage would take less time, what is the estimated difference in lost production under a failed-PHT scenario, versus a planned replacement scenario?

d) Is it appropriate for the Ontario ratepayer to bare 100% of the lost production cost and risk?

Response

a) Yes, the production forecast includes eight mini-outages to mitigate the risk of PHT pump motors failing before they can be replaced in planned outage cycles or in the Unit 2 Refurbishment window.

Evidence shows that the old motors on Units 3, 4, and 1 are at high risk of failure before their refurbishment windows occur, so only the Unit 2 motors can be replaced during the refurbishment window. Mini outages are necessary due to the motors' high risk of failure and there is likelihood that the some of the planned motor replacements will not make their planned outage schedules. Motors have failed before they could be replaced in 2015 and 2016 causing significant losses at Darlington.

b) No, the eight outages represent 3.371 TWh over the test period.

c) It is estimated that the difference in lost production under a PHT pump motor failure scenario versus a planned replacement scenario is approximately three days saved, or 0.063 TWh, providing there is an available spare (new or overhauled motor). If there are no motors available in a multi motor failure scenario, the unit could be offline for up to nine months. Alternatively, if a used motor is installed a subsequent outage would be required to replace it. It is also preferable to replace these motors in a planned manner as opposed to run to failure as this minimizes the nuclear safety risk of having a tripped motor trigger shutdown safety systems and liquid relief valves and lowers the risk of damage to fuel. A planned replacement schedule allows removed motors to be refurbished and reused at a lower cost than new motors.

d) OPG believes it is appropriate to include, as part of its rate filing, outage plans and associated costs that are required to replace end of life components needed for the operation of the nuclear units, particularly ones that pose such a significant risk to production. OPG bears 100% of production forecast risk.

SEC Interrogatory #49

Issue Number: 5.1
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

Reference:
[E2/1/1]

For each 6 month delay in refurbishment of Darlington unit 2, please provide the revised production forecast per year. Please also provide the change in proposed payment amounts as a result.

Response

The production impact of a 6-month delay in the refurbishment of Darlington Unit 2 would not affect the production forecast in 2017, 2018 or 2019. The impact of a 6-month delay on the production forecast in 2020 and 2021 is based on the assumption that the delay would push the start of refurbishment of Unit 3 back by the same amount. Such a delay would result in the first mini post commissioning outage of 55 days being delayed from 2020 into 2021 and the second mini post commissioning outage of 31 days being delayed from 2021 outside the rate period. The estimated production impact would be a gain of production of 55 days in 2020, representing about 1.1 TWh, and a corresponding loss of production of 24 days in 2021, representing about -0.5TWh.

The resulting changes in payment amounts cannot be provided, as they would depend on the specific causes of the assumed 6-month delay and the actions taken to address them. Any attempt to develop 6-month delay scenarios and quantify the range of potential impacts on the payment would be completely speculative, depending entirely on the assumptions made about the causes of the delay and OPG's responsive actions.

SEC Interrogatory #50

Issue Number: 5.1
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

Reference:
[E/2/1/1]

Please provide a table showing each of OPG's planned outages: i) a general description of the outage, ii) the timing of the outage, iii) the length of the outage, iv) the specific units affected, and v) the forecast production (TWh) lost due to the outage.

Response

Please see response to L-5.1-5 CCC-24.

SEC Interrogatory #51

Issue Number: 5.1
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

Reference:
[E2/1/1, p.7]
With respect to OPG's notice to the IESO regarding a planned outage:

a) How much notice does OPG generally give the IESO with a request for approval of planned outage?

b) How often does the IESO not approve an OPG planned outage?

c) When it does deny an outage request, generally how much delay is caused when the outage will ultimately take place as compared to the requested date?

Response

a) OPG submits its planned nuclear outage schedule to the IESO when it finalizes its business plan in order to secure a priority position in the schedule. This is done as much as three years or more in advance.

b) It is rare for the IESO not to approve a planned outage. Generally, OPG plans outages during periods where there is minimum risk of them being rejected by the IESO. OPG works with the IESO well in advance of the outage start date to minimize the risk that the planned outage is not approved.

c) As per above, it is a rare occurrence for IESO to deny an outage request. A recent example of a delay was the P1561 outage where the start was delayed from September 15, 2015 to September 20, 2015.

SEC Interrogatory #52

Issue Number: 5.1
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

Reference:

[E2/1/2] Please discuss the OPG's actual 2016 nuclear production forecast to date as compared to the forecast.

Response

As of the end of September, OPG's 2016 nuclear production forecast is 45.9 TWh compared with the budget of 46.8 TWh. Production is forecast to be 0.9 TWh below budget overall for a combination of reasons, some of which offset, including higher than planned forced loss rate at Darlington (1.93% forecast versus 1.00% budget), the extension of the P1561 outage into 2016, forced extensions to planned outages (FEPO) at Pickering for units 4, 6 and 8, offset by the cancellation of the planned mini outage on unit 1, as well as better than projected forced loss rate at Pickering (4.4% forecast versus 5.0% budget).

VECC Interrogatory #19

Issue Number: 5.1
Issue: Is the proposed nuclear production forecast appropriate?

Interrogatory

Reference:
Reference: E2/T1/S2/Table 1

a) Please provide a table similar to Table 1 which provides the information by individual units (Darlington and Pickering) and for the period 2013-2020. For simplification please leave out the "change" and "OEB approved" columns.

Response

Please see Attachment 1.

Actual Versus Planned Forecast By Operating Unit 2013-2020
Requested for 5.1-VECC-19 - OEB Rating Filing 2017-2021

Operating Unit	2013 Actual	2014 Actual	2015 Actual	2016 Budget	2017 Plan	2018 Plan	2019 Plan	2020 Plan
Darlington Unit 1								
TWh	7.5	5.8	5.5	7.5	5.2	7.1	7.0	5.2
Unit Capability Factor (%)	98.5	75.7	72.4	99.0	69.6	93.6	92.9	69.7
PO Days (excludes Refurb)	0	77	72	0	108	20	23	108
Refurb PO Days	0	0	0	0	0	0	0	0
FEPO Days	0	0	2	0	0	0	0	0
FLR (%)	1.3	2.2	8.3	1.0	1.0	1.0	1.0	1.0
FLR Days Equivalent	4.6	6.1	23.9	3.7	2.6	3.4	3.4	2.6
Darlington Unit 2								
TWh	5.1	7.4	6.4	5.9	-0.2	-0.2	-0.2	4.7
Unit Capability Factor (%)	67.6	96.9	84.3	99.0	0.0	0.0	0.0	72.2
PO Days (excludes Refurb)	78	3	50	0	0	0	0	58
Refurb PO Days	0	0	0	78	365	365	365	45
FEPO Days	20	0	0	0	0	0	0	0
FLR (%)	7.1	2.2	2.0	1.0	0.0	0.0	0.0	12.0
FLR Days Equivalent	18.8	8.0	6.4	2.9	0.0	0.0	0.0	31.6
Darlington Unit 3								
TWh	7.3	7.5	5.0	7.1	7.0	5.3	7.4	0.8
Unit Capability Factor (%)	96.6	98.8	65.7	93.6	92.9	71.0	98.3	99.0
PO Days (excludes Refurb)	0.0	0.0	95.8	20.0	22.5	103.3	2.5	0.0
Refurb PO Days	0.0	0.0	0.0	0.0	0.0	0.0	0.0	321.0
FEPO Days	0.0	0.0	5.8	0.0	0.0	0.0	0.0	0.0
FLR (%)	3.4	1.2	8.6	1.0	1.0	1.0	1.0	1.0
FLR Days Equivalent	12.2	4.2	22.4	3.5	3.4	2.6	3.6	0.5
Darlington Unit 4								
TWh	5.2	7.3	6.5	5.6	7.0	7.1	5.4	7.0
Unit Capability Factor (%)	69.0	96.0	85.2	74.4	92.9	93.6	72.1	92.9
PO Days (excludes Refurb)	66.5	11.8	48.8	91.0	22.5	20.0	99.1	22.5
Refurb PO Days	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FEPO Days	20.1	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FLR (%)	9.3	0.6	1.5	1.0	1.0	1.0	1.0	1.0
FLR Days Equivalent	25.9	2.1	4.7	2.8	3.4	3.4	2.7	3.4
Pickering Unit 1								
TWh	2.0	3.9	2.6	3.8	1.8	3.7	2.7	3.8
Unit Capability Factor (%)	47.1	87.6	58.0	84.4	41.7	83.8	61.6	83.8
PO Days	0.0	0.0	128.4	33.7	204.9	43.0	128.5	43.0
FEPO Days	109.7	0.0	17.3	0.0	0.0	0.0	0.0	0.0
FLR (%)	32.2	12.4	2.5	7.0	5.0	5.0	5.0	5.0
FLR Days Equivalent	81.6	45.1	5.5	23.4	8.0	16.1	11.8	16.2
Pickering Unit 4								
TWh	3.9	2.8	4.3	2.9	3.7	2.6	3.7	2.3
Unit Capability Factor (%)	86.7	63.6	95.3	65.6	83.8	57.5	83.8	52.3
PO Days	20.0	85.3	0.0	107.8	43.0	144.1	43.0	164.5
FEPO Days	4.5	34.3	0.0	0.0	0.0	0.0	0.0	0.0
FLR (%)	6.9	5.3	4.7	7.0	5.0	5.0	5.0	5.0
FLR Days Equivalent	23.5	12.9	17.3	18.2	16.1	11.0	16.1	10.1
Pickering Unit 5								
TWh	2.6	4.3	2.9	4.3	2.3	4.2	2.3	4.3
Unit Capability Factor (%)	58.7	95.8	66.1	96.0	53.2	95.0	51.9	95.0
PO Days	87.8	0.0	105.9	0.0	160.7	0.0	165.6	0.0
FEPO Days	53.4	0.0	14.7	0.0	0.0	0.0	0.0	0.0
FLR (%)	1.8	4.1	0.5	4.0	5.0	5.0	5.0	5.0
FLR Days Equivalent	3.8	14.9	1.1	14.6	10.2	18.3	10.0	18.3
Pickering Unit 6								
TWh	3.0	4.0	3.0	4.3	2.7	4.2	2.1	4.3
Unit Capability Factor (%)	67.6	88.7	68.0	96.0	60.4	95.0	48.1	95.0
PO Days	113.0	0.0	102.4	0.0	133.0	0.0	180.1	0.0
FEPO Days	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
FLR (%)	0.1	11.3	5.3	4.0	5.0	5.0	5.0	5.0
FLR Days Equivalent	0.3	41.3	13.8	14.6	11.6	18.3	9.2	18.3
Pickering Unit 7								
TWh	4.3	2.8	4.2	2.9	4.2	2.0	4.2	3.0

Unit Capability Factor (%)	95.4	62.2	93.3	65.2	95.0	44.6	95.0	68.4
PO Days	0.0	113.9	0.0	117.5	0.0	193.5	0.0	102.5
FEPO Days	0.0	7.5	8.5	0.0	0.0	0.0	0.0	0.0
FLR (%)	4.6	6.6	3.3	4.0	5.0	5.0	5.0	5.0
FLR Days Equivalent	16.7	16.2	11.7	9.9	18.3	8.6	18.3	13.2
Pickering Unit 8								
TWh	3.9	2.4	4.3	2.6	4.2	2.5	4.2	2.0
Unit Capability Factor (%)	86.8	53.8	95.5	58.6	95.0	55.9	95.0	46.0
PO Days	0.0	85.7	13.4	142.6	0.0	150.2	0.0	188.9
FEPO Days	0.0	13.6	0.0	0.0	0.0	0.0	0.0	0.0
FLR (%)	13.2	25.6	0.7	4.0	5.0	5.0	5.0	5.0
FLR Days Equivalent	48.0	67.7	2.3	8.9	18.3	10.7	18.3	8.9